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October 17, 2003

ELECTRONICALLY FILED ON OCTOBER 17, 2003
Dennis L. Keschl, Esq., Administrative Director
Maine Public Utilities Commission
State House Station 18
Augusta, ME 04333

Re: Maine Public Service Company, Request for Approval
of Alternative Rate Plan
MPUC Docket No. 2003-085

THIS IS A VIRTUAL DUPLICATE OF THE ORIGINAL HARDCOPY SUBMITTED TO THE COMMISSION IN ACCORDANCE WITH ITS ELECTRONIC FILING INSTRUCTIONS

Dear Mr. Keschl:

Enclosed for filing please find a Supplemental Stipulation in the above-captioned Docket which has been executed by the Public Advocate and Maine Public Service Company. Counsel to McCain Foods, Inc. and J.M. Huber, Inc. has advised us that she has already forwarded a signed signature page on behalf of those parties.

Stipulation Exhibits D-1 and SC-1 contain confidential information. Redacted versions are being filed herewith. We will file the confidential versions of these Exhibits under separate cover (via regular mail) and subject to the Protective Order in this Docket.

Very truly yours,

Scott L. Sells, Esq.

cc: Service List, via electronic mail

STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2003-85

MAINE PUBLIC SERVICE COMPANY,)
Request for Approval of Alternative Rate Plan)

SUPPLEMENTAL STIPULATION

A. Procedural Background. On September 3, 2003, the Commission entered an Order Approving Stipulation (Part One) approving the Partial Stipulation submitted by the parties on August 28, 2003 in the above-captioned Docket. On September 10, 2003, Maine Public Service Company ("MPS," or the "Company") executed the Hedge Program described in the Partial Stipulation, as evidenced by the documentation filed by MPS with the Commission on September 12. On September 25, 2003, the Commission entered Part Two of its Order Approving Stipulation.

On September 11, 2003, MPS made a compliance filing consisting of draft rate sheets and associated exhibits pursuant to the requirements of the Commission's September 3 Order. In the course of the parties' review of this filing, it was discovered that an error had occurred in the development of the transmission component of MPS's retail rates ("TCRR"). The error lead to an incorrect allocation of the total company pro forma test year revenue between the TCRR and the distribution component of MPS's retail rates ("DCRR"). Specifically, the error caused the TCRR revenue to be higher, and the DCRR revenue to be correspondingly lower, than would have been the case had the error not occurred. (A narrative detailing the impact of the error on various MPS filings is attached as Appendix A.)

The Hearing Examiner entered a Procedural Order on September 26, 2003 identifying this issue and scheduling a Technical Conference for September 30, 2003 to address how this problem should be resolved.

On October 2, 2003, MPS filed its Responses to six Oral Data Requests issued at the September 30 Technical Conference. Thereafter, the parties and the Advisory Staff have held discussions regarding the issues raised in the Examiner's September 26 Procedural Order and have now identified a recommended disposition of these issues, as embodied in this Supplemental Stipulation.

B. Supplemental Stipulation. The parties agree as follows:

1. Impact of Error. The TCRR error caused the TCRR to be overstated as of October 1, 2002. In addition, use of the incorrect TCRR in developing pro forma test year revenue for the purpose of this Docket caused an overstatement of test year pro forma transmission revenues. Since test year pro forma distribution revenues are determined residually, the overstatement of test year pro forma transmission revenues resulted in a corresponding understatement of test year pro forma distribution revenues in this Docket.

2. Revisions to Partial Stipulation Exhibits. Attached hereto are the Exhibits filed on August 28, 2003 with the Partial Stipulation, with the following revisions[1]:

(i) Exhibit 1 has been revised to reflect the corrected test year distribution revenue and increase required to meet the agreed-upon revenue requirement, which remains unchanged;

(ii) Exhibit 3 has been revised to show the correct allocation of test year distribution and transmission revenues;

(iii) Exhibit SC-2 has been revised to reflect the properly-determined TCRR for the Rate HT Class;

(iv) Exhibit D-1 has been revised to show the allocation of the properly-determined distribution costs among rate classes; and

(v) Exhibit R, a new exhibit which shows MPS's current rates, corrected to remove the effect of the TCRR error.

The parties hereby agree (i) to amend the Partial Stipulation submitted on August 28, 2003 to substitute the aforementioned revised Exhibits in place of the Exhibits originally filed, and that (ii) the set of Exhibits in the form attached hereto constitutes the complete and final set of Exhibits to the Partial Stipulation.

3. New Compliance Rate Filing. The Company should be directed to file new compliance rates, with accompanying work sheets, designed to implement:

(i) a DCRR increase of no more than $685,037,

(ii) a total distribution revenue requirement of no more than $16,068,714, and

(iii) any FERC-approved change to its TCRR that MPS may wish to implement, to be accomplished by updating its Terms and Conditions and its tariff to reflect such change

all as shown on the Exhibits described in subsection 2 above. The new rates shall go into effect for service rendered on and after November 1, 2003.

4. Handling of Overcharges. Set forth in its Response to Item 6 of the September 30 Oral Data Requests is MPS's determination of the additional TCRR-related revenue it collected for the period October 1 through December 31, 2002 as a result of the TCRR error. Also included therein is an estimate of the additional revenue it will have collected by October 31, 2003. Following the implementation of new retail rates in this Docket, MPS shall determine the total additional revenue it received as a result of the TCRR error and submit its calculations

[1] Exhibits that have been revised are marked "REVISED." Exhibit R has been marked "NEW" as it was not included in the original Stipulation.

thereof to the Staff and the parties for review. The parties shall strive to agree by December 31, 2003 on (a) an accurate total of the additional revenues collected as a result of the TCRR error during the period October 1, 2002 through the date new rates become effective pursuant to this Docket (the "Extra Revenues"), and (b) the proper flow through of the Extra Revenues (i.e., a methodology for returning or refunding the Extra Revenues to customers).

5. Record. In considering this Supplemental Stipulation, the Commission may review and consider the Responses to the September 30 Oral Data Requests, and the balance of the record in this Docket.

C. Standard Stipulation Provisions.

A. Purpose; Rejection of Portion Constitutes Rejection of Whole. The parties are entering into this Supplemental Stipulation for the purpose of finally disposing of all issues raised in the Examiner's September 26 Procedural Order. If the Commission does not accept the entire Supplemental Stipulation without material modification, then this Supplemental Stipulation shall be null and void, and will not bind the parties in this proceeding.

B. No Precedent. The making of this Supplemental Stipulation by the parties shall not constitute precedent as to any matter of fact or law, nor, except as expressly provided otherwise herein, shall it foreclose any party from making any contention or exercising any right, including the right of appeal, in any other Commission proceeding or investigation, or in any other trial or action.

C. Examiner's Report. The parties agree to waive the provisions of § 752 (b) of the Commission's Rules of Practice and Procedure, requiring that any Examiner's Report be in writing and that the parties be afforded an opportunity to file exceptions or comments thereon. The parties thereby intend to permit the Advisors either to provide an oral Examiner's Report to the Commission at the deliberative session to be held in this Docket, or, if the Advisors so wish, to provide a written Examiner's Report to the Commission with the parties waiving the right to file exceptions or comments thereto.

IN WITNESS WHEREOF, the parties have caused this Partial Stipulation to be executed and delivered, or have caused their lack of objection to be noted, by their respective attorneys.

MAINE PUBLIC SERVICE COMPANY

Dated: 10/16/03

By: [signature]

MCCAIN FOODS, INC.

Dated:____________ By:______________________________

J.M. HUBER, INC.

Dated:____________ By:______________________________

OFFICE OF THE PUBLIC ADVOCATE

Dated: 10/16/03 By:______________________________

APPENDIX A TO
SUPPLEMENTAL STIPULATION
DOCKET 2003-85
MPS ARP CASE

The following narrative describes the sequence of events surrounding the development of the incorrect TCRR and the impact of the error on MPS's rates.

* Per FERC Docket ER00-1053 and MPUC Docket's 98-577 and 99-185, MPS proposed the unbundling of retail transmission rates. In FERC Docket ER00-1053, MPS introduced a new MPS OATT formula Schedule 1.1.2, a schedule of retail revenue requirement and retail transmission ("T") rates based on energy for non-demand customers, and on billing demand for demand customers for TY1999 (the first year).

* On June 1, 2001, FERC Schedule 1.1.2 was updated to adjust for the new retail T revenue requirement per the MPS OATT formula. The billing units used were not correct. Demand values for classes ES, EP, EST, EPT, ST, and HT appear to have been based on ten months of TY2000 demands. This resulted in proportionately lower class demands for the above classes and proportionately higher demand rates. The billing-unit-related error affected only the rate unbundling (the allocation of transmission versus distribution revenues) and did not affect the rates charged to customers. Also at June 1, 2001, the Company updated its twelve coincident peak ("12-CP") allocation of the T revenue requirement to rate classes base on proportional change in class energy from TY1999.

* On June 1, 2002, FERC Schedule 1.1.2 was again updated to adjust for the new retail T revenue requirement per the MPS OATT formula. The TY2000 billing demands for classes ES, EP, EST, EPT, ST, and HT developed above were adjusted proportionately to the change in energy from TY2000 to TY2001 to develop TY2001 demand rates. Non-demand customers' rates were based on class energy reflected in MPS's financial report. Thus, the original error in Schedule 1.1.2 was carried forward into the revised version of this Schedule. Also at June 1, 2002, the Company updated its 12-CP allocation factors based on the same methodology used in 2001.

* At October 1, 2002, MPS filed its FERC approved T rates with the MPUC. The MPUC approved the rates and T&C page 76, which incorporated the above-developed retail T rates in total rates (MPUC Docket No. 2002-479).

* In this Docket (MPUC Docket No. 2003-85), the Company used the TY2000 and TY2001 retail transmission rates in its analysis to unbundle its DCRR by first subtracting out of total rates the retail transmission rates (weighted 9 months TY2000 and 3 months TY2001 corresponding to the effect of the October 1, 2002 retail transmission rate change) and retail Stranded Cost rates (also determined in this proceeding). TY2002 billing units including demand billing units were carefully developed and applied to these rates to develop the corresponding revenues.

* The Parties have agreed to use TY2002 12-CP allocation factors as a proxy for TY2000 and TY2001 12-CP allocation factors for the purposes of establishing "starting-point" rates.

REVISED
Stipulation
Exhibit 1
Summary

STATE OF MAINE
PUBLIC UTILITIES COMMISSION
DOCKET 2003-85
Stipulated Distribution Revenue Requirement

	Without Interest Lock	With Estimated Interest Lock	With Actual Interest Lock
Net Expenses (1)	12,567,615	12,567,615	12,567,615
Rate Base	29,870,211	29,870,211	29,870,211
Cost of Capital	10.69%	11.72%	11.74%
Return on Rate Base	3,194,272	3,501,099	3,507,184
Total Test Year Revenue Rquirement	**15,761,887**	**16,068,714**	**16,074,799**
Less: Weather Normalization	(36,801)	(36,801)	(36,801)
Less: Current Electric Revenue	(15,346,876)	(15,346,876)	(15,346,876)
Increase Required	**$378,210**	**$685,037**	**$691,122**

(1) Revenue Offset Included on Net Expenses			
Forfeited Discounts	81,286	81,286	81,286
Misc Service Revenues	171,305	171,305	171,305
Rent from Electric Property	195,315	195,315	195,315
Other Electric Revenues	0	0	0
Unbilled Revenues	0	0	0
Special Discount Revenue Offset	122,118	122,118	122,118
Total	570,024	570,024	570,024

Stipulation
Exhibit 2
Cost of Capital

STATE OF MAINE
PUBLIC UTILITIES COMMISSION
DOCKET 2003-85
Stipulated Cost of Capital

Without Interest Rate Hedge Program

	Proportion	Cost	WACC	Pre-Tax WACC
Common Equity	51.00%	10.25%	5.23%	8.70% (1)
Short-Term Debt	7.60%	4.16%	0.32%	0.32%
Long-Term Debt	41.40%	4.06% (2)	1.68%	1.68%
Total	100.00%		7.22%	10.69%

Note (1):

Federal Tax Rate of:	34.0000%
State Tax Rate of:	8.9300%
Weighted Tax Rate of:	39.8938%

1 / (1 - 0.398938) = 1.66370

Note (2): Excludes Interest Rate "Hedge" Program

With Estimated Interest Rate Hedge Program

	Proportion	Cost	WACC	Pre-Tax WACC
Common Equity	51.00%	10.25%	5.23%	8.70%
Short-Term Debt	7.60%	4.16%	0.32%	0.32%
Long-Term Debt	41.40%	6.54% (3)	2.71%	2.71%
Total	100.00%		8.25%	11.72%

Note (1):

Federal Tax Rate of:	34.0000%
State Tax Rate of:	8.9300%
Weighted Tax Rate of:	39.8938%

1 / (1 - 0.398938) = 1.66370

Note (3): Per Stipulation, the 6.54% value is a "place holder'" and is subject to adjustment based on the actual cost to MPS of its Hedge Program, which cost shall be determined following the execution of the Program.

With Actual Interest Rate Hedge Program

	Proportion	Cost	WACC	Pre-Tax WACC
Common Equity	51.00%	10.25%	5.23%	8.70%
Short-Term Debt	7.60%	4.16%	0.32%	0.32%
Long-Term Debt	41.40%	6.59% (4)	2.73%	2.73%
Total	100.00%		8.27%	11.74%

Note (1):

Federal Tax Rate of:	34.0000%
State Tax Rate of:	8.9300%
Weighted Tax Rate of:	39.8938%

1 / (1 - 0.398938) = 1.66370

Note (4): The long-term debt cost of 6.59% is based on the actual executed cost to MPS of its Hedge Program

REVISED
Stipulation
Exhibit 3
Test Year Revenue

STATE OF MAINE
PUBLIC UTILITIES COMMISSION
DOCKET 2003-85
Adjusted Test Year 2002 Revenue

	Transmission $	Distribution $	Stranded $	Total $	FR Total $
ORIGINAL STIPULATION					
1 Total without Proforma per Staff Exhibit at 7/22/03 - Test-Year 2002	2,793,667	15,059,488	11,637,287	29,490,442	29,502,113
2 Proforma Adjustments		32,425			
3 Total with Proforma per Staff Exhibit at 7/22/03	2,793,667	15,091,913	11,637,287	29,522,867	
4 Weather Normalization	0	36,801	0	36,801	
5 Stipulation Increase as of 9/3/03	0	940,000	0	940,000	
6 Rate Year Revenue as Predicted -- 1/1/2002 thru 12/31/02, (ie. No T increase)	2,793,667	16,068,714	11,637,287	30,499,668	
7 **Rate Year Revenue as Ordered**	**2,793,667**	**16,068,714**	**11,637,287**	**30,499,668**	
REVISED STIPULATION					
8 Reallocation of Transmission Revenues	(254,963)	254,963			
9 Rate Year Revenue adjusted for Proper Transmission Allocation	2,538,704	15,346,876	11,637,287	29,522,867	
10 Weather Normalization		36,801		36,801	
11 Transmission Increase for Rate Year 11/1/02 - 10/31/03	264,579	0		264,579	
12 Stipulated Increase for Rate Year 11/1/03 - 10/31/04	441,938	685,037		1,126,975	
13 **Revised Rate Year Revenue**	**3,245,221**	**16,068,714**	**11,637,287**	**30,951,222**	

Stipulation
Exhibit 4
Rate Base

Maine Public Service Company

Stipulated Distribution Ratebase

13-month Average ending December 31, 2002

Net Utility Plant:	
Electric Plant in Service	64,444,706
Less: Accum Prov for Depre & Amort	(29,824,677)
Customer Advances for Const	(124,821)
Balance, Net Utility Plant	34,495,208
Plus: Proforma for AMR	994,000
Invest in Sub and Associated Co's:	
Investment in MEPCO	494,655
Working Capital Requirement	827,528
Rate Base Adjustments:	
Non-Investor Supplied Capital	
Customer Deposits	(29,920)
Pension Accrual-SFAS 87	(1,791,721)
Other Post Employ Benefits-SFAS 106	(76,943)
Deferred Director's Compensation	(90,961)
Accum. Deferred Income Taxed-Dep Prop	(4,572,311)
- Seabrook	0
- Other	(379,324)
Balance-Total Adjusted Rate Base	29,870,211

Stipulation
Exhibit 5
Expenses

Maine Public Service Company
Stipulated Distribution Net Expense

Transmission Operations Expense	0
Transmission Maintenance Expense	0
Distribution Operations Expense	751,631
Distribution Maintenance Expense	1,217,675
Customer Account Expenses	1,290,237
Administration & General Exp-Oper.	6,262,001
Administration & General Exp-Maint.	300,300
Depreciation - Transmission Plant	0
Depreciation - Distribution Plant	1,766,614
Depreciation - General Plant	381,832
Amortization - Stranded Costs	0
Amortization - Other	177,436
Taxes Other than Income	1,095,296
Investment Tax Credit Adjustment	(19,869)
Total Operating Expenses	13,223,153
Offsets to Total Operating Expenses:	
Equity in Earnings of MEPCO	85,514
Equity in Earnings of M.Y.	0
MPS Revenue Offset	570,024
Revenue Requirement-Net Expense	**12,567,615**

Stipulation
Exhibit 6
Conservation

Maine Public Service Company
Conservation Funding

To reflect an increase in conservation fund expenses from 0.541% of electric retail revenues ($29,502,113) to 0.6 mills/kWh multiplied by total retail sales (530,279,363) pursuant to the Order in MPUC Docket No. 2002-162 dated April 4, 2003.

Current MPS conservation fund assessment:	159,606
Ordered MPS conservation fund assessment:	318,168
Increase to Operating Expense	158,561

		Ordered Level		
		% on Total Delivery Rates	mils/kWh	$000's
2001	Actual	0.53%	0.30	157.26
2002	Actual	0.54%	0.30	159.61
2003	Budget	1.08%	0.60	318.17
2004	Forecast	1.44%	0.80	424.22
2005	" "	1.80%	1.00	530.28
2006	" "	2.16%	1.20	636.34
2007	" "	2.52%	1.40	742.39
2008	Forecast	2.70%	1.50	795.42

Supplemental
Stipulation
Exhibit 7
VERP and Rate
Case Expenses

MAINE PUBLIC SERVICE COMPANY
Amortization of Voluntary Early Retirement Program and Rate Case Expenses

1. To reflect amortization of 2002 VERP costs over seven years.

Total cost of VERP:	
FAS 88 (Pension) one time cost:	$231,124
FAS 106 (Retiree Medical) one time cost:	170,747
Total increase to operating expense:	401,871
7-year amortization:	$57,410

2. To reflect amortization of costs incurred in connection with Docket No. 2003-85.

Outside Rate Case Expenses Allowed to be Collected in Distribution Rates:	
Total Expense:	$214,249
Number of Years:	7
Annual Expense:	$30,607

Stipulation
Exhibit 8
Prior Orders

MAINE PUBLIC SERVICE COMPANY
Special Discount Revenue Offset
Test Year December 31, 2002

To adjust test year for an increase in Special Discount Revenue Offset revenues due to prior Orders in MPUC Docket No. 2001-240.

Order dated February 27, 2002	
Amount through 12/31/02	$112,500
Amount 1/1/03 through 6/30/03	67,500
Order dated March 11, 2003	
Amount 3/1/03 through 6/30/03	19,236
Total	199,236
2-Year Amortization	$99,618
Reversal of Special Discounts in the Test Year as of February 28, 2003:	**135,000**
Total increase in revenue:	**$234,618**

REDACTED

REVISED
Stipulation
Exhibit D-1

Maine Public Service Company
Allocation of Distribution Costs to Rate Classes
Docket No. 2003 - 85

	TY2002			
Class	Annual kWh	Total per FR - $	Total Dist. $	Total Dist. %
A	159,504,140	$12,018,285	7,492,765	48.93%
AH/AN	9,984,398	653,917	364,911	2.38%
C	72,440,873	5,184,770	3,022,138	19.73%
F	11,667,394	802,043	453,728	2.96%
D	2,530,992	103,973	38,871	0.25%
ES & MC-M	92,622,296	4,592,308	1,802,969	11.77%
EP	11,218,060	574,035	220,689	1.44%
EST	4,339,843	190,306	69,578	0.45%
EPT	18,353,500	776,764	274,637	1.79%
ST	44,962,000	2,035,487	547,608	3.58%
HT - Core	8,330,400	464,154	54,682	0.36%
[redacted]				
SL-T	3,344,987	774,229	701,745	4.58%
Test Year Total	530,267,283	$29,502,113	15,314,450	100.00%

Proforma Adjustments:

[redacted]

Test Year Distribution Revenue per Stipulation Exhibit 3: 15,346,876

REDACTED

REDACTED

Stipulation
Exhibit SC-1

Maine Public Service Company
Allocation of Stranded Costs to Rate Classes
Docket No. 2003 - 85

	TY2002			
Class	Annual kWh	Total per FR - $	Total SC $	Total SC %
A	159,504,140	$12,018,285	3,794,839	32.61%
AH/AN	9,984,398	653,917	237,544	2.04%
C	72,440,873	5,184,770	1,787,013	15.36%
F	11,667,394	802,043	287,818	2.47%
D	2,530,992	103,973	65,102	0.56%
ES & MC-M	92,622,296	4,592,308	2,298,460	19.75%
EP	11,218,060	574,035	278,385	2.39%
EST	4,339,843	190,306	100,463	0.86%
EPT	18,353,500	776,764	437,520	3.76%
ST	44,962,000	2,035,487	1,178,112	10.12%
HT - Core	8,330,400	464,154	304,643	2.62%
[redacted]				
SL-T	3,344,987	774,229	67,362	0.58%
Test Year Total	530,267,283	$29,502,113	11,637,287	100.00%

REDACTED

REVISED
Stipulation
Exhibit SC-2

Maine Public Service Company

Rate HT (Includes McCain and Huber Transmission and Distribution Rates)
by Components

	Revised Rates 03/01/2000 thru 09/30/2002				Revised Rates effective 10/01/2002			
Rate Class	TY2000 TDS Wires Rate $/unit	TY2000 Transmission $/unit	TY2000 Distribution $/unit	TY2000 Stranded Cost $/unit	TY2001 Transmission $/unit	TY2000 Distribution $/unit	TY2000 Stranded Cost $/unit	10/1/2002 TDS Wires Rate $/unit
Transmission Service (H-T)								
Customer Charge ($/Mo)	505.38	0.00	45.21	460.17	0.00	45.21	460.17	505.38
Winter Peak Energy ($/kWh)	0.033288	0.00	0.002978	0.030310	0.00	0.002978	0.030310	0.033288
Winter Off-Peak Energy ($/kWh)	0.018714	0.00	0.001674	0.017040	0.00	0.001674	0.017040	0.018714
Summer Peak Energy ($/kWh)	0.013115	0.00	0.001173	0.011942	0.00	0.001173	0.011942	0.013115
Summer Off-Peak Energy ($/kWh)	0.007373	0.00	0.000660	0.006713	0.00	0.000660	0.006713	0.007373
Winter Peak Demand ($/kW)	8.11	1.64	1.05	5.42	1.97	1.05	5.42	8.44
Winter Off-Peak Demand ($/kW)	4.05	1.64	0.52	1.89	1.97	0.52	1.89	4.38
Summer Peak Demand ($/kW)	5.40	1.64	0.81	2.95	1.97	0.81	2.95	5.73
Summer Off-Peak Demand ($/kW)	2.71	1.64	0.52	0.55	1.97	0.52	0.55	3.04

Maine Public Service Company
Starting Point Delivery Rates
Docket No. 2003 - 85

Rate Class	Dkt. 2003-85 Starting Rates Post 10/01/2002 T Rate (restated)	D+S Rate	T&D Rate
Residential (A/A1)--Flat			
1st 100 kWh or Less ($)	0.50	6.93	7.43
100<kWh<400 ($/kWh)	0.005026	0.069335	0.074361
kWh>400 ($/kWh)	0.005026	0.069335	0.074361
Residential (AH/AHN)			
Winter			
1st 100 kWh or Less ($)	0.50	6.93	7.43
100<kWh<600 ($/kWh)	0.005026	0.069335	0.074361
kWh>600 ($/kWh) disc 41%	0.005026	0.039456	0.044482
Summer			
1st 100 kWh or Less ($)	0.50	6.93	7.43
100<kWh<400 ($/kWh)	0.005026	0.069335	0.074361
kWh>400 ($/kWh)	0.005026	0.069335	0.074361
General Service (C)			
Customer Charge ($/Mo)	0.00	11.46	11.46
Winter Energy ($/kWh)	0.005882	0.073661	0.079543
Summer Energy ($/kWh)	0.005882	0.044010	0.049892
General Service (F)			
Customer Charge ($/Mo)	0.00	11.46	11.46
Winter Energy ($/kWh)	0.005882	0.065802	0.071684
Summer Energy ($/kWh)	0.005882	0.044010	0.049892
Large Primary Service (EP)			
Customer Charge ($/Mo)	0.00	104.32	104.32
Winter Energy ($/kWh)	0.000000	0.029096	0.029096
Summer Energy ($/kWh)	0.000000	0.012719	0.012719
Winter Demand ($/kW)	1.88	8.54	10.42
Summer Demand ($/kW)	1.88	5.02	6.90
Large Primary TOU (E-P-T)			
Customer Charge ($/Mo)	0.00	126.87	126.87
Winter Peak Energy ($/kWh)	0.000000	0.038831	0.038831
Winter Off-Peak Energy ($/kWh)	0.000000	0.023205	0.023205
Summer Peak Energy ($/kWh)	0.000000	0.018755	0.018755
Summer Off-Peak Peak Energy ($/kWh)	0.000000	0.011208	0.011208
Winter Peak Demand ($/kW)	1.78	9.07	10.85
Winter Off-Peak Demand ($/kW)	1.78	3.83	5.61
Summer Peak Demand ($/kW)	1.78	5.55	7.33
Summer Off-Peak Peak Demand ($/kW)	1.78	2.06	3.84
Large Secondary Servic (ES)			
Customer Charge ($/Mo)	0.00	39.69	39.69
Winter Energy ($/kWh)	0.000000	0.031460	0.031460
Summer Energy ($/kWh)	0.000000	0.012585	0.012585
Winter Demand ($/kW)	2.05	10.45	12.50
Summer Demand ($/kW)	2.05	6.37	8.42

Maine Public Service Company
Starting Point Delivery Rates
Docket No. 2003 - 85

Large Secondary TOU (E-S-T)			
Customer Charge ($/Mo)	0.00	62.67	62.67
Winter Peak Energy ($/kWh)	0.000000	0.043384	0.043384
Winter Off-Peak Energy ($/kWh)	0.000000	0.026897	0.026897
Summer Peak Energy ($/kWh)	0.000000	0.020787	0.020787
Summer Off-Peak Peak Energy ($/kWh)	0.000000	0.012887	0.012887
Winter Peak Demand ($/kW)	2.60	9.77	12.37
Winter Off-Peak Demand ($/kW)	2.60	3.65	6.25
Summer Peak Demand ($/kW)	2.60	5.69	8.29
Summer Off-Peak Peak Demand ($/kW)	2.60	1.60	4.20
Sub-Transmission Service (S-T)			
Customer Charge ($/Mo)	0.00	126.56	126.56
Winter Peak Energy ($/kWh)	0.000000	0.035071	0.035071
Winter Off-Peak Energy ($/kWh)	0.000000	0.020170	0.020170
Summer Peak Energy ($/kWh)	0.000000	0.018411	0.018411
Summer Off-Peak Peak Energy ($/kWh)	0.000000	0.010588	0.010588
Winter Peak Demand ($/kW)	2.29	6.34	8.63
Winter Off-Peak Demand ($/kW)	2.29	2.18	4.47
Summer Peak Demand ($/kW)	2.29	3.57	5.86
Summer Off-Peak Peak Demand ($/kW)	2.29	0.79	3.08
Transmission Service (H-T)			
Customer Charge ($/Mo)	0.00	505.38	505.38
Winter Peak Energy ($/kWh)	0.000000	0.033288	0.033288
Winter Off-Peak Energy ($/kWh)	0.000000	0.018714	0.018714
Summer Peak Energy ($/kWh)	0.000000	0.013115	0.013115
Summer Off-Peak Peak Energy ($/kWh)	0.000000	0.007373	0.007373
Winter Peak Demand ($/kW)	1.97	6.47	8.44
Winter Off-Peak Demand ($/kW)	1.97	2.41	4.38
Summer Peak Demand ($/kW)	1.97	3.76	5.73
Summer Off-Peak Peak Demand ($/kW)	1.97	1.07	3.04
Municipal Pumping (D2)			
Customer Charge ($/Mo)	0.00	88.18	88.18
Winter Energy ($/kWh)	0.000000	0.048727	0.048727
Summer Energy ($/kWh)	0.000000	0.025080	0.025080
Street Lighting (SL)			
HPS 4,000	0.04	9.25	9.29
HPS 5,800	0.05	9.71	9.76
HPS 9,500	0.07	10.55	10.62
HPS 16,000	0.10	12.19	12.29
HPS 27,000	0.18	16.95	17.13
HPS 50,000	0.29	23.56	23.85
HG 3,850	0.07	8.86	8.93
HG 7,950	0.13	10.68	10.81
HG 21,000	0.28	15.75	16.03
HG 57,000	0.67	33.06	33.73
FL 8,600	0.11	13.94	14.05
FL 23,000	0.28	23.15	23.43
Poles	0.00	4.69	4.69
Area Lighting (T)			
HPS 5,800	0.05	8.99	9.04
HPS 9,500	0.07	9.96	10.03
HPS 27,000	0.19	17.58	17.77
HPS 50,000	0.29	22.09	22.38
HG 7,950	0.13	10.08	10.21
HG 21,000	0.28	18.15	18.43
Poles	0.00	4.69	4.69